Modeling Long-Term Capacity Expansion Options for the Southern African Power Pool (SAPP)

African Economic Policy
Discussion Paper Number 27
July 1999

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Funded by
United States Agency for International Development
Bureau for Africa
Office of Sustainable Development
Washington, DC 20523-4600

ABSTRACT

Long-term planning for the expansion of capacity in transmission and generation demands the attention of electricity utilities in both the highly industrialized regions and the less industrialized regions of the world. While utilities in the developed nations have long recognized the need for regional, rather than local planning, primarily for reliability purposes, utilities in less developed nations are rapidly catching up, as the reliability and economic benefits of joint construction and utilization planning overcome perceived national needs for country autonomy. Purdue University's State Utility Forecasting Group (SUFG), in collaboration with utility staff in the Southern African nations, has developed a mixed integer cost minimizing optimization model for the Southern Africa Power Pool (SAPP). This is to help SAPP develop least cost expansion and utilization plans, enabling members to assess the benefits of such joint planning. From 1997 until the present, this modeling activity, funded by USAID, has involved collaborative research and data collection between researchers at Purdue and the engineers and managers of the twelve national electricity utilities of the Southern Africa Region.

This paper describes the results from running the model with time horizons of eight and twenty years with generation and transmission expansion for the SAPP. Details of the formulation that form the model are available from earlier SUFG publications [1-10]. The total present value costs over the twenty-year time horizon are in the order of twelve billion dollars. The model minimizes the total expansion and production costs in an integrated manner, which includes transmission. The inclusion of transmission constraints in the expansion model is particularly important, since shortages in transmission capacity have been hindering the substitution of clean, cheap hydropower from the north for the more expensive, polluting thermal power in the south of the region. With a relaxed country autonomy constraint, initial simulations show savings of $700 million when compared to simulations where each country always maintains enough capacity in reserve to meet a predetermined fraction of domestic demand. This is regardless of the economic benefits of depending on imports. This paper is in four parts: I) SAPP Background; II) The Eight Year Run; III) The Twenty Year Run; and IV) The Impact of Forecast Uncertainty.

Keywords: Present value cost minimization, long-term transmission planning, Southern African Power Pool, mixed integer linear programming.

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Acknowledgements

The authors would like to thank USAID and the staff associated with its EAGER (Equity and Growth through Economic Research) program for the funding to do this work. Many thanks must also be given to the engineers and managers of the SAPP utilities for all the provision of data and lively dialogue and discussion over the past two years. The contributions from students in Purdue's School of Industrial Engineering have been decisive in making the project so successful. Purdue's State Utility Forecasting Group (SUFG) staff provided the modeling and technical expertise throughout.

Note

A slightly modified version of this discussion paper has been submitted for publication in the Proceeding of the Third IASTED International Conference on Power and Energy Systems, November 8-10, 1999.

I. SAPP Background

The twelve countries included in the SAPP–Purdue model are Angola, Botswana, Democratic Republic of Congo (DRC), Lesotho, Malawi, Mozambique, Namibia, Republic of South Africa (RSA), Swaziland, Tanzania, Zambia, and Zimbabwe. The thermal and hydropower generating capabilities by the year 2000 are listed in Tables 1 and 2 for each country. The region has excess hydropower in DRC, Zambia, and Mozambique. The majority (95%) of South Africa's massive current generating capacity of over 38,000 MW is provided by coal fired stations.

From the point of view of peak demand the size of the utilities in the SAPP region could be classified into three categories; large (South Africa, Figure 1), medium (Zimbabwe, Zambia, and DRC, Figure 2), and small (Botswana, Lesotho, Mozambique, Namibia, and Swaziland, Figure 3). The largest utility (Eskom) in South Africa is predominantly thermal while the medium sized utilities are predominantly hydropower. The small utilities are a mix, with Mozambique being totally hydropower and Botswana being totally thermal.

The projected electricity demand growth rates for countries in the region vary from 1.8% to 13.1% for the period 1996 to 2020 (Table 3). The results in this paper are based upon the medium growth scenario, which has a regional average growth rate of 3.8%.

The practical transfer capacities of the international transmission lines for the year 2000 are shown in Figure 4.

Table 1. SAPP Thermal Generation Data for Existing Plants at Year 2000

Country & Station Name	PGmax (MW)	Country & Station Name	PGmax (MW)
Angola	113		
Botswana	118	RSA	
Lesotho	2	Arnot	1320
Mozambique		Duvha	3450
Beira	12	Hendrina	1900
Maputo	62	Kendal	3840
		Kriel	2700
Namibia		Lethabo	3558
Vaneck	108	Majuba	1836
Paratus	24	Matimba	3690
		Matla	3450
Zimbabwe		Tutuka	3510
Hwange	956	Koeberg *	1840
Munyati	80	(* Nuclear)	
Harare	70	(Others)	5400
Bulawayo	120		
		Tanzania	
		GT10	37
Swaziland	9	LM6000	75

This figure also illustrates the locations of the fourteen nodes in the model. (Two countries, RSA and Mozambique, are represented by two nodes each, hence 14 nodes for 12 countries.) It can be seen that the existing interregional transmission system does not allow large scale hydro exports from 10 and 11 to the rest of the system.

The long-term model is a mixed integer mathematical program which, using the GAMS and CPLEX solver software, minimizes the present value of total costs (capital, fuel, operational and maintenance, and unserved energy) for SAPP over a user specified time horizon, subject to a set of constraints. The constraints include:

- Supply/demand equations, which insure that user specified demands are met for each hour modeled for each of the day types in each of the seasons;
- Capacity constraints, which insure that each plant's generation does not exceed current ()rated capacity;
- Reliability constraints, which insure that a proper reserve margin is maintained between installed or purchased capacity and peak demand;
- Country autonomy constraints, which insure that domestic capacity is always greater than a pre-determined fraction of domestic peak demand.

Three commodities are traded in the model:

a) Spot power to meet demand, obtained in the open market, with no guarantee of availability;
b) Firm power to meet demand, available up to a prescribed maximum guaranteed by the seller;
c) Firm capacity, which the buyer may use to satisfy reserve requirements, and which sets the upper limit on firm power imports.

The model contains more than 600 integer variables, which model the fixed costs of capacity expansion of the construction options (large coal, small coal, combined cycle, hydro, pumped hydro, AC & DC transmission lines). The model also contains 500,000 continuous variables representing such operating and maintenance costs for the available units for each hour, day, season, and year modeled and 20,000 constraints of the types described above.

The model can be run on a personal computer with the following specifications:

Pentium II BX 100 MHz motherboard
Pentium II 350 MHz processor
512 Mb 100 MHz RAM
9.61 Gb UWSCSI hard drive.

Typical run times vary from minutes to hours, depending on the number of declared binary and integer variables, horizons length, and knowledge of a good upper bound on the cost minimizing solution to the problem. The model can also be run in a UNIX environment.

The model software and operating instructions are non proprietary. Copies can be obtained by e-mail: clallen@ecn.purdue,edu; phone: (765) 494-7036; or fax: (765) 404-2351. The data provided by SAPP is, however, proprietary.

Many user options are allowed in the model: A few of the major options available include:

- Planning horizon options (variable years/period modeled)
- Reliability options (user specified margins for thermal, hydro, purchased capacity)

- Demand characterization options (variable hours/day)
- Financial options (cost of capital etc.)
- Supply options (including transmission)
- Construction costs options (fixed costs, variable costs)

Full details of the formulation are found in the Long-Term Model User Manual (Second Edition, January 1999), [1]. The long-term model is primarily designed for a twenty-year time horizon. SAPP countries are however also very concerned over the projects they have already identified, undertaking preliminary feasibility studies on their priority in a medium term perspective with an eight-year time horizon. Simulations are therefore made with both the eight and twenty year time horizons. The eight-year run of the model incorporates only the existing projects specified by the SAPP utilities. The longer twenty-year run adds in generic new stations (combined cycle, large and small coal and gas turbines), using current costs for the United States.

Table 2. SAPP Hydropower Generation Data for Existing Plants at Year 2000

Country & Station Name	Hmax (MW)	Country & Station Name	Hmax (MW)
Angola	121	Malawi	
	56	Nkala	124
	37	Tedzani I&II	40
	37	Tedzani III	60
	37		
DRC		RSA	
Inga	1775	Gariep	320
Nseki	248	Vanderkloof	220
Nzilo	108	Palmiet #	400
Mwadingusha	68	Drakensbur#	1000
Koni	42		
		Tanzania	
Lesotho		Kidatu	200
Muela	72	Mtera	80
		Pangani	68
Mozambique		Mumgu-Hale	29
HCB	2075		
Chic-Cor-Mav	81	Zimbabwe	
SMoz	16	KaribaSouth	666
		Zambia	
Namibia		KaribaNorth	600
Ruacana	240	Kafue	900
		Victoria	100
Swaziland	40	(# Pumped)	

Table 3. Electricity Demand Growth Rates for 1996 to 2020

COUNTRY	LOW % p.a.	MEDIUM % p.a.	HIGH % p.a.
Angola	6.2%	7.9%	10.5%
Botswana	3.7%	4.3%	6.0%

Lesotho	3.4%	6.1%	8.2%
Malawi	2.1%	3.2%	6.2%
Mozambique	8.9%	10.9%	13.1%
Namibia	5.7%	7.2%	8.5%
South Africa	1.8%	3.6%	5.5%
Swaziland	2.5%	3.4%	4.5%
Tanzania	4.0%	6.0%	7.7%
Zambia	2.7%	4.4%	6.4%
Zimbabwe	2.9%	4.1%	5.9%
SADC tot/weighted avg.	2.0%	3.8%	5.7%
South Africa	1.8%	3.6%	5.5%
Rest of SADC	3.6%	5.0%	6.9%

Source: Cape Town Modeling Workshop - P.B. Robinson, July 1998

II. The Eight-Year Run

This eight-year scenario seeks the least-cost mix of SAPP projects under the following assumptions:

- The generation and transmission capacity expansion options are limited to those proposed by SAPP.
- Capital recovery factors are set at 12% for hydro and transmission line projects, 15% for thermal plants.
- The planning horizon is eight years; consisting of choices in 2002, 2004, 2006, and 2008, with SAPP demand growing at the average (3.8%) yearly rate. The SAPP country average growth rates vary from 3.2%/year to 10.9%/year.
- Initial (2000) capacity includes existing capacity, plus those committed projects approved at the Cape Town meeting in July 1998, and modified since then [3].
- The country autonomy constraint is relaxed, no longer requiring that a country construct enough domestic generation capacity to meet peak requirements without relying on imports.
- Each country is only required to maintain a reserve margin (met by either domestic capacity or purchased capacity) consistent with SAPP guidelines (19% for thermal, 10% for hydro).
- Initial Fuel and O & M operating expenses are, where possible, taken from SAPP documents (coal \$.30 to \$.60/10^6 BTU: gas, \$1.10 to \$3.00/10^6 BTU).
- Such costs escalate at model default values (1%).
- Water cost \$1.50/MWh.
- Unforced outage rate, 7 to 11%, depending on the equipment.

- Forced outage rates, 3 to 10%, depending on the equipment.
- O & M in the $.0006 to $.005/KWh range.
- Transmission outages proportional to distance.

The results of this scenario run are shown in Figure 5. The numbers are the MW of thermal and hydro (circled at the nodes) and transmission (boxed along the arcs) capacity installed over the eight-year horizon. Several characteristics of the solution stand out. Almost 4/5 of the total cost is in the variable cost of operation of existing and new generation units, as the system chooses to utilize regional existing capacity to the fullest extent possible before constructing new facilities. Variable costs are dominated by fuel cost (75%) followed by O & M (16%) and water use charges (10%). (This is somewhat arbitrary, since no consensus exists on proper opportunity costs for water; the model uses $1.50/MWh). Thermal and hydro expansion costs (2/3 of total expansion cost) are fairly evenly spread over the eight year horizon, while transmission cost (1/3 of expansion costs) are concentrated in the beginning and end of the planning period.

Figure 1. Republic of South Africa's Electricity Demand (MW), July 24, 1997

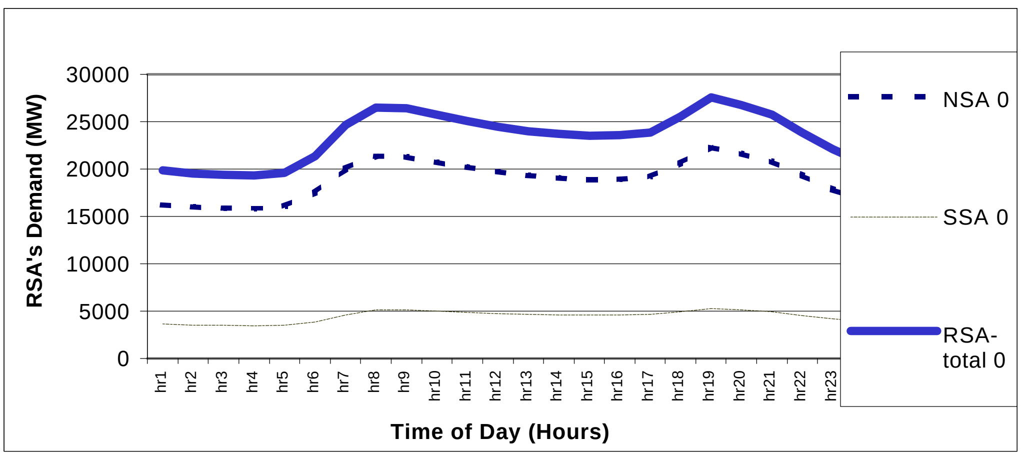
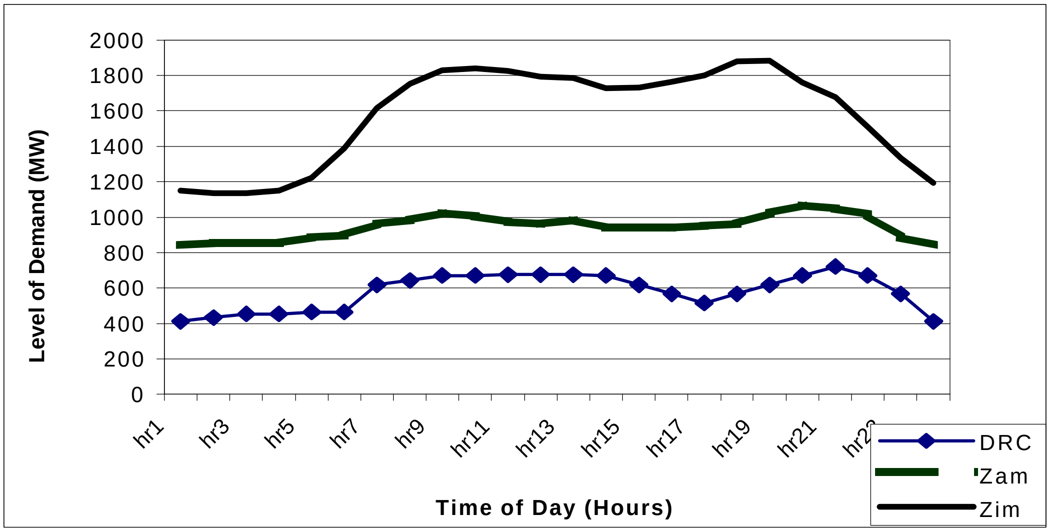


Figure 2. Electricity Demand in Democratic Republic of Congo, Zambia, and Zimbabwe, July 24, 1997

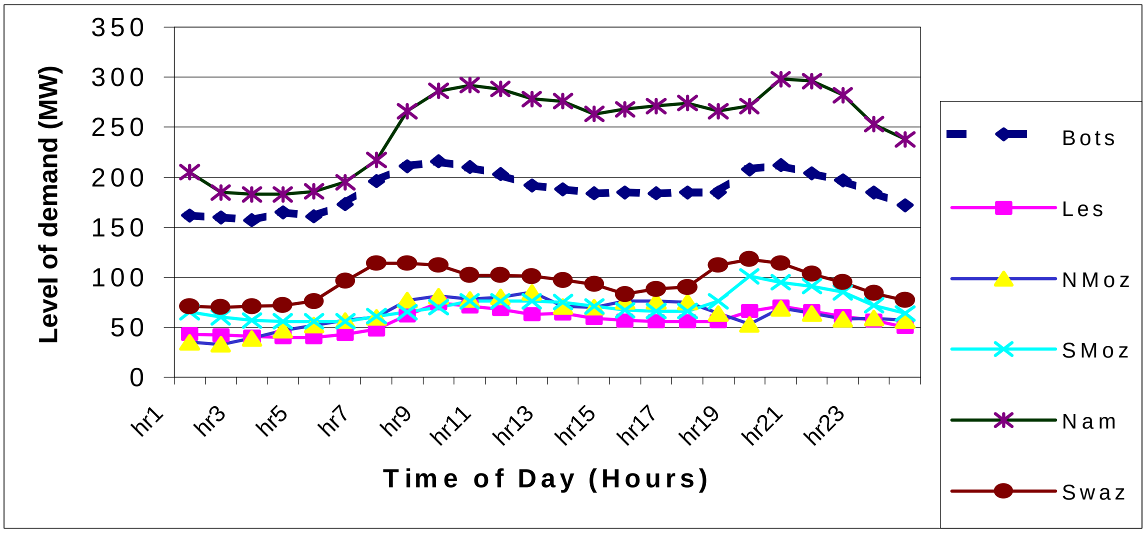


Substantial (40%) resources are devoted to improving the transmission system. Early in the planning period, this involves increasing the capacity of the DRC/Zambia/Zimbabwe/RSA "spine" of SAPP to allow the substitution of cheap excess capacity in the north to forestall the need for new construction in the south. Towards the end of the planning period, the model invests in an alternate north-south route through Angola, Namibia, and RSA to create a competitive path for hydropower to flow from north to south.

New hydro construction represents almost three-quarters of new MW construction - 2860 of the 4700 MW the model calls for. Of this total, over half (2000 MW) is devoted to constructing new pumped hydro facilities, which, in effect, allows thermal plants to mimic the energy storage advantages of standard hydro facilities. The remainder of the hydro investments are along the two "spines" of the SAPP system, involving hydro construction in Zambia and Zimbabwe early in the planning period, and Angola and Namibia towards the end.

Thermal construction is limited to the recommissioning of a substantial amount of currently mothballed small coal capacity, whose cost/kW is extraordinarily inexpensive when compared to new thermal capacity and construction of gas turbines. As a result, while thermal capacity additions represent about 40% of total new MW generation installed, they represent less than 1/10 of total expansion cost.

Figure 3. Electricity Demand in Botswana, Lesotho, Mozambique, Namibia, and Swaziland, July 24, 1997



III. The Twenty Year Run

The following assumptions were made in the twenty-year demonstration run . The planning horizon was over 20 years, allowing choices to be made in 2005, 2010, 2015, and 2020; For this scenario, SAPP demand growth was again at the average rate. The set of capacity expansion options was expanded to include the construction of generic plants, whose cost and performance data were taken from a recent U.S. study. The country autonomy constraint remained relaxed, only requiring that SAPP countries satisfy their reserve requirements by a mixture of domestic thermal and hydro capacity with purchased capacity from others.

The results of this scenario are shown in Figure 6. Again, new generation capacity is circled and transmission capacity is boxed. In contrast to the eight-year case just described, expansion costs are a substantial (40%) portion of total system costs. This is to be expected, as system demand catches up, and then surpasses system supply, over the longer planning horizon. Fuel costs again dominate operating costs. Thermal and hydro costs are a much larger fraction (85%) of total expansion costs; transmission costs represent only 15% of total expansion costs.

The vast majority of additional MW is devoted to new generation construction, rather than transmission. This is not because transmission expansion substantially decreased as the horizon lengthened, but rather because of the substantial increase (5 fold!) in the need for new generation, as the planning horizon extended into the years where substantial generation deficits exist.

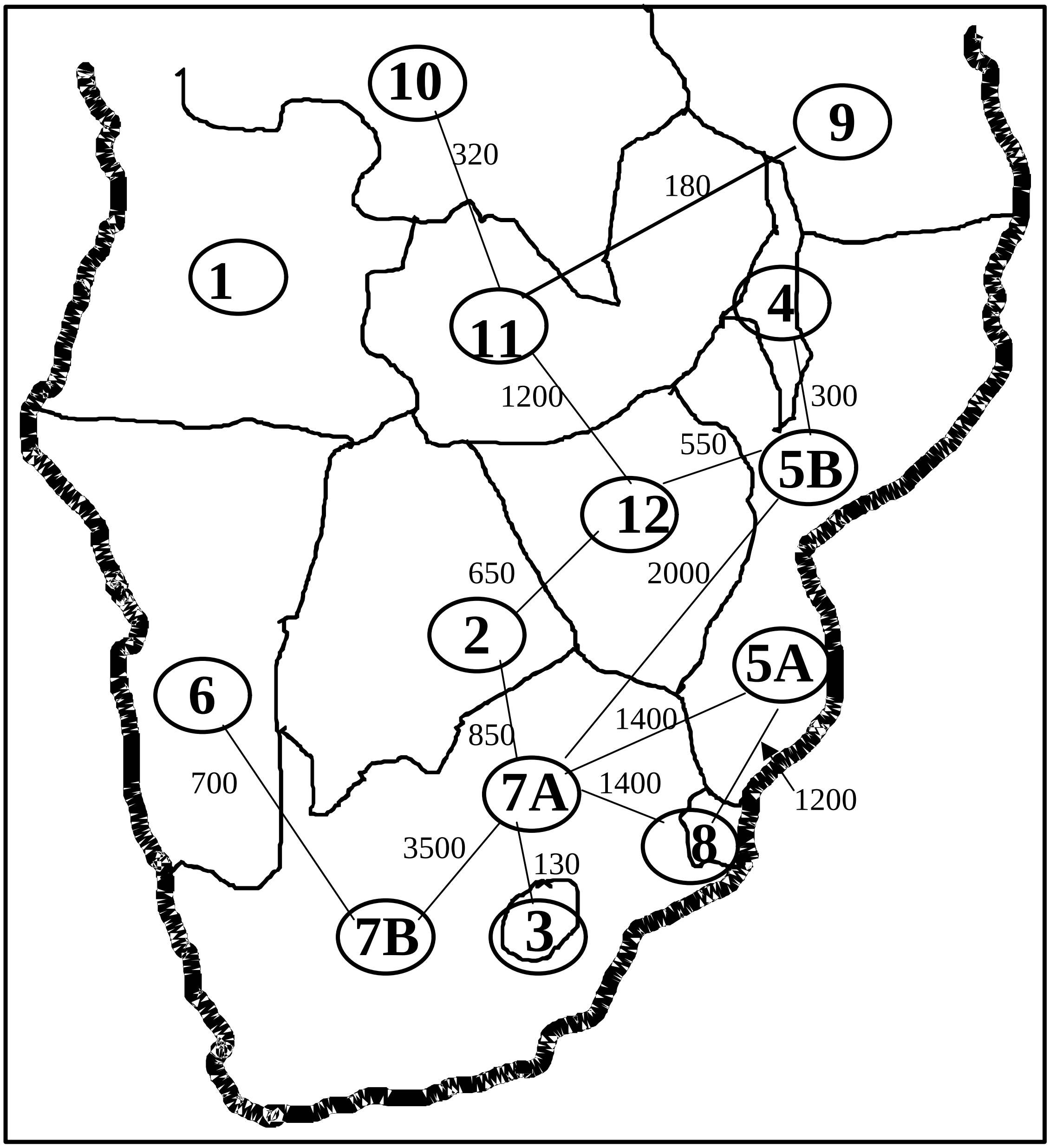
The general pattern of transmission capacity expansion found in the eight-year run is maintained in the longer twenty-year run model. That is, initially invest in the DRC/Zambia/Zimbabwe/RSA "spine", then build the western route from DRC through Angola and Namibia to RSA.

In contrast to the eight-year model, thermal construction becomes a major (50%) part of the total construction dollar budget, and an even larger (greater than 70%) part of the MW total. Thermal construction is dominated by construction of over 6000 MW of large coal generation plants in the South, and a surprising amount of construction of generic combined cycle plants in those countries where a source of natural gas supply was identified. In addition, relatively small investments were made in small coal plants and generic gas turbines for peaking purposes, again restricted to those countries where gas was assumed available at competitive prices

New hydro and associated transmission construction was dominated by drawing on the resources of DRC's Inga site towards the end of the horizon; early hydro expansion was concentrated in hydro investments along the DRC/Zambia/Zimbabwe/RSA "spine", and in pumped storage investment in the south.

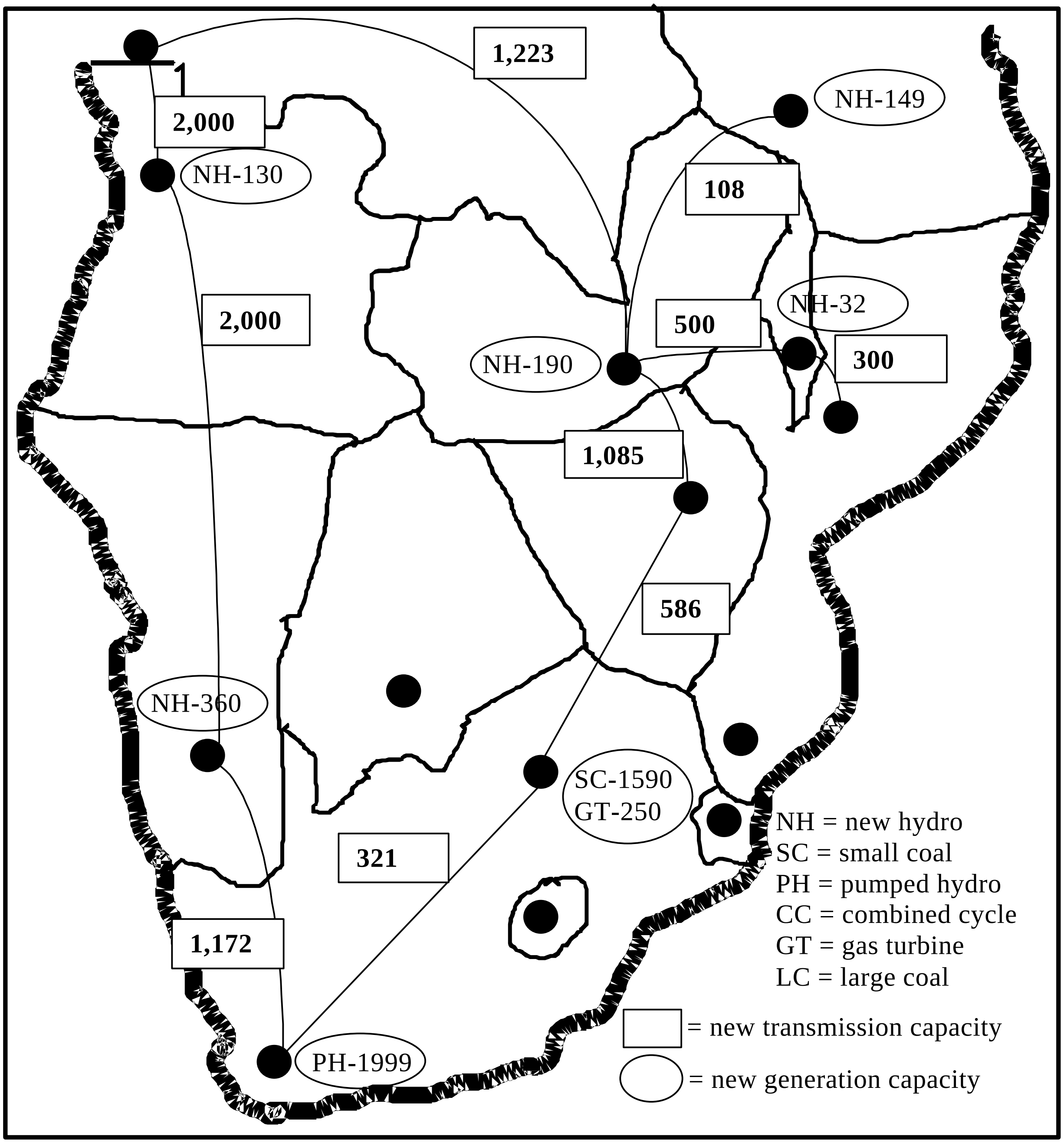
These results should be viewed with even more caution, if possible, than the results of the previous run. They assume SAPP has access to thermal technologies at the prevailing average of world costs. This may be a wildly optimistic assumption, given the peculiar nature of generation plant construction in the SAPP region. In particular, it assumes that the SAPP region can invest in the substantial infrastructure necessary to allow the bulk (all countries except Zambia, Malawi, Mozambique, Swaziland, and DRC) of SAPP members to have access to natural gas as a fuel source, either from domestic production or imports. Such access would allow SAPP members to benefit from the substantial advantages of gas fired combined cycle generation plants, which now dominate new construction in North America. (The assumption is easy to change by simply eliminating generic combined cycle plants from consideration.)

Figure 4. SAPP International Maximum Practical Transfer Capacities Existing or Committed for the Year 2000 (MW) [Supplied by Eskom (South Africa), December 1998]



1. Angola (H)	4. Malawi	7A. N. South Africa (T)	10. DRC
2. Botswana (T)	5A. S. Mozambique (H)	7B. S. South Africa	11. Zambia (H)
3. Lesotho	5B. N. Mozambique	8. Swaziland	12. Zimbabwe (H, T)
	6. Namibia (H, T)	9. Tanzania (H, T)	

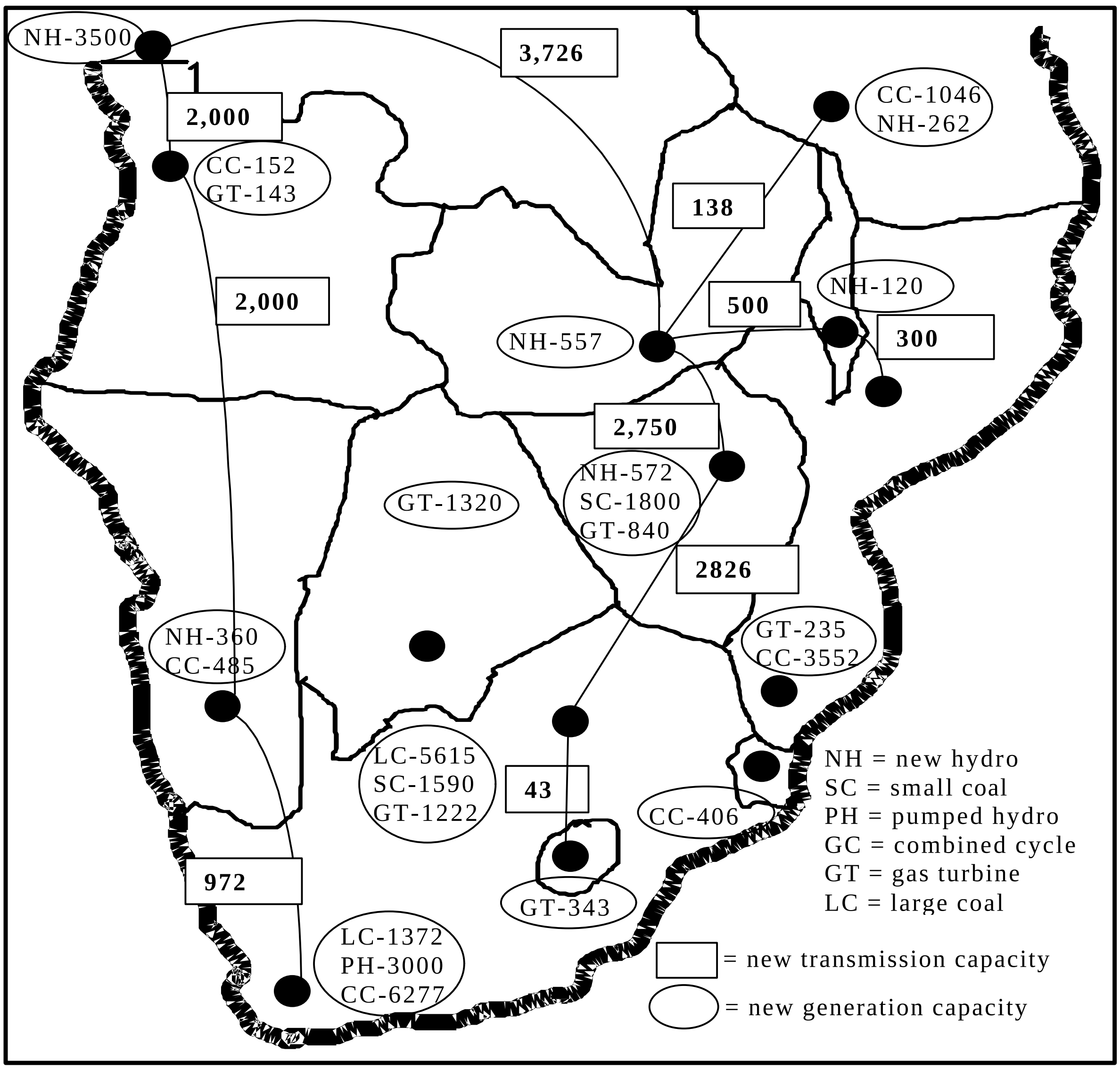
Figure 5. Expansion Results of 8-year Horizon Model, with Country Autonomy Constraint Relaxed (all units in MW)



IV. The Impact of Forecast Uncertainty

In the face of the considerable uncertainty associated with electricity growth projections, planning new construction is a risky proposition anywhere it is practiced. The costs of underestimating demand growth result in the system paying the extra costs involved with the construction of units with short lead times, as the system tries to rapidly make up the deficiency in generation supply to meet unexpected higher demand. Conversely, the costs of over-estimating demand growth involve the costs of canceling unnecessary projects planned in anticipation of greater expected demand.

Figure 6. Expansion Results of 20-Year Planning Horizon, Country Autonomy Constraint Relaxed (all units in MW)



In Tables 4, 5, and 6, an example is shown of how the model can be used as a decision aid in deciding on what expansion plan to adopt – one optimized for low, medium, or high growth. Table 4 shows, along the diagonal, the costs associated with correctly predicting the demand scenarios for the growth scenarios, with no forecast error, e.g. these scenarios do in fact take place.

Let us consider what happens if a given growth strategy is implemented but a different scenario develops. Table 5 shows the consequences of such forecast error, either in terms of the MW deficit (-) if demands are greater than expected, or the surplus (+) if demands are less than expected, broken down by generation type. There are many methods of determining the costs of these deficits or surpluses. The methods used in our study are described as follows:

a) Assume the shortage cost is the extra cost involved with having to rush construction of expensive small generation units to make up the deficit, here taken to be the difference in the high cost KWh of meeting unexpected demand from a series of small combustion turbines, which have small construction lead-times, and the lower cost per KWh of meeting these same demands with larger, more economic units with much longer construction lead-times.

b) Assume the excess capacity cost is the added cost of cancellation of the (now) unnecessary plants started in anticipation of high demands, here taken as 100% of the construction cost of hydro (e.g. construction on these must proceed) and 20% of the construction cost of the thermal plants (i.e. cancelation costs are assumed at 20% of the full cost).

Table 6 shows the results of the assumptions. As the table indicates, in every instance, the cost of building less capacity than is actually needed is less than the corresponding cost of building too much capacity. Thus, if these "over and under" estimation costs are correct, it pays to plan for low or medium growth, but never for high growth. Of course this conclusion would be altered if it were determined that the cost of making up a shortage in capacity was more than the cost of canceling unnecessary plants.

Currently, the project is focusing on the impact of enforcing the country autonomy constraints on SAPP-wide construction and operating costs. Initial runs indicate that while the capital cost to the members will be substantial, imposing the country autonomy constraints does not reduce electricity trade as much as was expected. The reason is instructive. Countries, while constructing sufficient capacity to insure self-sufficiency, still have the incentive to substitute other countries' low operating cost capacity for their own higher operating cost capacity even though that capacity is idle, being held for reserve purposes.

V. Summary

The modeling support for SAPP from Purdue continues until June 2000. Significant changes in the demonstration expansion plans described are expected. A change in the expected capital costs of any one project makes a totally different expansion plan. Modifications to the reserve and autonomy factor constraints also make major changes in the results of these demonstration runs.

Several important lessons for electricity planners have been learned so far from this project:

- In planning for loosely connected systems, as are typically found in developing, rather than developed economies, it is important to use a model which is capable of simultaneously considering capacity expansion of both the generation and transmission systems.

- The costs of individual utility self-sufficiency can be substantial, particularly when large hydro projects compete with smaller thermal projects. However, self-sufficiency does not imply no trade; it still is economic to trade, even when all countries hold enough capacity to satisfy domestic demand.

- It is critical to include the fixed costs of new plant and transmission construction in such a modeling effort; this involves a considerable increase in run time when compared with standard linear programming formulations. Consequently, care should be taken in the selection of the hardware and software used to solve the models.

By late 1999 the model will also operate with a windows interface facility. This will make the model very user friendly. Together with the PC platform, it will mean that the model will be able to be run in any country of the world by many types of users. The wide interest shown in the model and its great breadth of application, for minimizing transmission and capacity expansion as well as operational costs, gives indication of its becoming a powerful planning tool.

Table 4. The Impact of Forecast Error Cost Minimizing Capacity Expansion/Utilization– Three Scenarios

	Actual Growth		
Optimal Strategy	Low (2%)	Medium (3.8%)	High (5.7%)
Low Growth (2%)	$5.8 x 10^9		
Med Growth (3.8%)		$11.3 x 10^9	
Hi Growth (5.7%)			$23.4 x 10^9

Table 5. Capacity Shortages (-) and Surpluses (+) Resulting from Forecast Error

	Actual Growth		
Optimal Strategy	Low (2%)	Medium (3.8%)	High (5.7%)
Low Growth (2%)	0	-32,500 MW	-86,300 MW
Med Growth (3.8%)	+23,900 MW Thermal +8600 MW Hydro 32,500 MW Total	0	-53,800 MW
Hi Growth (5.7%)	+72,450 MW Thermal +13,900 MW Hydro +86,300 MW Total	+48,500 MW Thermal +53,000 MW Hydro +53,800 MW Total	0

Table 6. Estimated Total Cost, if Forecast in Error

	Actual Growth		
Optimal Strategy	Low (2%)	Medium (3.8%)	High (5.7%)
Low Growth (2%)	$\$5.8 \times 10^9$	5.8×10^9 $+7.2 \times 10^9$ 13×10^9	5.8×10^9 $+19 \times 10^9$ $\$24.8 \times 10^9$
Med Growth (3.8%)	5.8×10^9 $+12.9 \times 10^9$ Hydro $+ 4.8 \times 10^9$ Thermal 23.5×10^9 Total	$\$11.3 \times 10^9$	11.3×10^9 $+11.8 \times 10^9$ 23.1×10^9
Hi Growth (5.7%)	5.8×10^9 $+20.5 \times 10^9$ Hydro $+ 14.5 \times 10^9$ Thermal 40.8×10^9 Total	11.3×10^9 $+7.87 \times 10^9$ Hydro $+9.7 \times 10^9$ Thermal 29.0×10^9 Total	$\$23.4 \times 10^9$

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